D. *Duke Should Utilize Only Eighteen Months of Market Prices Before Transitioning to a Fundamentals Forecast*

Q115. Given the major issues associated with market prices discussed above, do you believe that market prices have any role in establishing Duke's natural gas forecast?

A115. Yes, although their role should be limited. I have shown above that the price of the ten-year swap that Duke uses is nearly identical to the price of futures contracts, and thus the issue with illiquidity and volatility in futures market prices translates into to swap prices. I have also shown that the long-term portion of the futures curve reflects short-term volatility in a manner that is inconsistent with deep structural changes to the natural gas market that would drive such divergence in actual long-term prices. Finally, I have shown that locking in a forecast mere weeks earlier or later can have outsized impacts on ten years of market prices.

In response to this, Duke should limit its use of market prices to the near-term and take steps to avoid the daily volatility inherent in natural gas derivative markets. I recommend that the Company calculate the market price of futures contracts three years forward using the average of the daily settlement price for the month preceding the earliest contract closing date. I also recommend that Duke calculate the average based on the most recently available report from at least two fundamentals-based forecasts such as EIA AEO or IHS Markit. I further recommend that Duke use market prices for 18 months, transition linearly between market prices and a fundamentals-based forecast over the next 18 months and proceed fully on the fundamentals forecast for month 37 and forward.

Q116. How would this work in practice?

A116. Duke began modeling for this IRP in summer 2020. If the Commission determines that Duke has not met its obligations under Act 62 and must update its modeling, it must render that decision by June 28, 2021.[136] In that instance, Duke should update its modeling to use market

[136] Details for Docket 2019-224-E, https://dms.psc.sc.gov/Web/Dockets/Detail/117181. Accessed 1/29/21.

prices starting in July 2021. The Company would determine the forward market price by averaging the settlement prices between May 17, 2021 and June 28, 2021 for July 2021 through June 2024 futures contracts.[137] There is no need for Duke to obtain or procure quotes from ten-year fixed swaps as it has been shown that these prices are functionally equivalent to the futures prices in the near term.

Duke would then obtain the most recent fundamentals-based forecast from at least two reputable sources. One of these sources should be EIA's AEO as it is a broadly available, open-source model that is readily available to intervenors. Duke would use market prices for the first 18 months, transition linearly to the average of the fundamentals-based models, and exclusively use the average of the fundamentals-based model after month 36.

Q117. DO YOU HAVE ANY INFORMATION HOW OTHER UTILITIES HANDLE THE MIX OF MARKET PRICES AND FUNDAMENTALS-BASED IN DEVELOPING THEIR NATURAL GAS PRICE FORECASTS?

A117. Yes. The Staff of the North Carolina Utilities Commission ("NCUC") conducted a survey of several utilities in the Southeast and around the country and "did not identify any utilities other than DEC and DEP that rely wholly on forward prices for terms greater than six years."[138] Further, other Duke subsidiaries in Florida, Kentucky, and Indiana relied on market prices for five years before transitioning over five year to fundamentals-based forecasts.[139]

Other utilities studied by NCUC Staff included TVA (which transitioned fully to fundamentals-based forecast in year six), Georgia Power (using the current year plus two years of market prices), Southwestern Public Service Company (a simple average of market prices and three fundamentals-based forecasts from the beginning of the planning horizon), and Puget Sound Energy (three years of market prices before switching to a fundamentals-based forecast). DEC and DEP are clear outliers.

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[137] Futures contracts close three days before the end of the calendar month.

[138] Initial Statement of the Public Staff at 22, February 12, 2019, Docket No. E-100, Sub 158, North Carolina Utilities Commission.

[139] *Id.*

Q118. DUKE HAS COMPLAINED IN THE PAST THAT FUNDAMENTALS-BASED MODELS IN GENERAL AND EIA'S AEO IN PARTICULAR LAG MARKET PRICES AND ARE THUS INEFFECTIVE IN PREDICTING PRICES IN THE NEAR TERM. WHAT IS YOUR RESPONSE TO THIS CRITIQUE?

A118. Duke's critique that fundamentals-based forecasts are slower to react to short-term pricing trends is not without merit; however, the directionality of the time lag cuts both ways. In its arguments in North Carolina's Avoided Cost proceeding, Duke suggested that its market purchases "demonstrate the stability of long-term natural gas market prices over the past few years" compared to fundamentals-based forecasts.[140] In support of this statement, it produced a low-resolution graph showing that market prices had flatter increases and were more closely bunched than fundamentals-based forecasts. This figure is reproduced below as Figure 27.

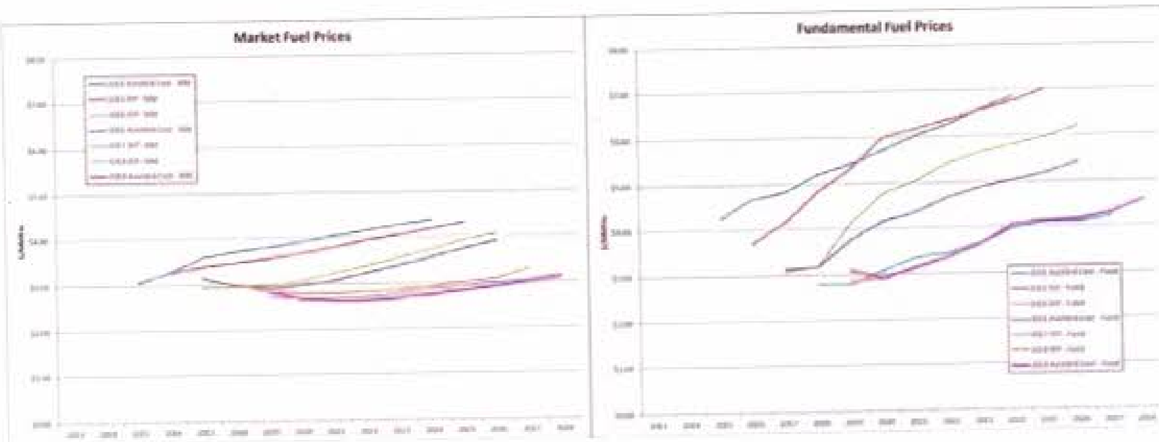

Figure 27 - Duke NC Avoided Cost Proceeding Market Prices vs. Fundamentals Chart

The left graph shows the ten-year forward price of market purchases made between 2014 and 2018 in IRP and avoided cost proceedings, while the right graph shows "fundamental fuel prices" over the same time frame. Duke did not publicly disclose the sources of these figures, but one can reasonably assume that the market prices are based on previous small swap

[140] See e.g. *Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress* at 18, LLC at 18, Docket No. E-100, Sub158, State of North Carolina Utility Commission. March 27, 2019. (NC Avoided Cost proceeding).

purchases and the fundamentals based on forecast from groups such as EIA AEO or IHS Markit.[141]

Q119. WHAT DO YOU OBSERVE ABOUT THESE FIGURES?

A119. As an initial matter, the projections embedded in these charts are of little consequence. These figures were produced on March 27, 2019, meaning that any price projection past that time was unknown and could not be verified against actual results.[142] Duke cannot claim that market price forecasts are more accurate than fundamentals-based forecasts in the future until we reach the future.

EIA has produced a retrospective analysis of its forecasts going back to 1993 that compares the projections of future years to the actual prices that are realized.[143] Figure 28 below shows the forecast error for its AEOs from 1994 through 2020, with darker lines corresponding to earlier forecasts and lighter lines corresponding to more recent forecasts. Forecasts from early AEOs (darker lines) were consistently below eventual market prices, while those from later AEOs (lighter lines) were consistently above eventual market prices.

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[141] DEP IRP Report at 5.
[142] And as shown above, these whims can be quite significant.
[143] Annual Energy Outlook Retrospective Review. Available at https://www.eia.gov/outlooks/aeo/retrospective/.

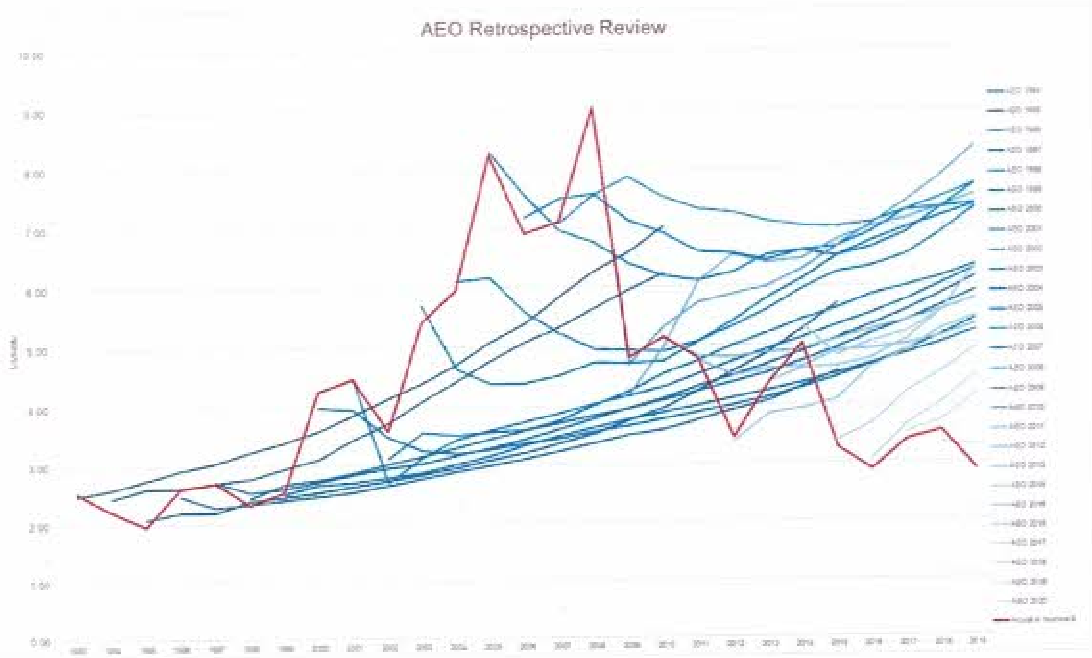

Figure 28 - AEO Retrospective Review – Natural Gas Prices

Figure 29 below shows the forecast error of the myriad AEOs. The lagging nature of fundamentals-based forecasts is evident, although the magnitude of its error has fallen in recent years. In forecasts just before the fracking boom drove down prices (e.g. AEO 2008-2010), estimates for future prices were substantially higher than prices that were eventually realized. But during periods when natural gas prices were rising faster than anticipated (e.g. AEO 2000-2003), forecasted prices were substantially under market prices.

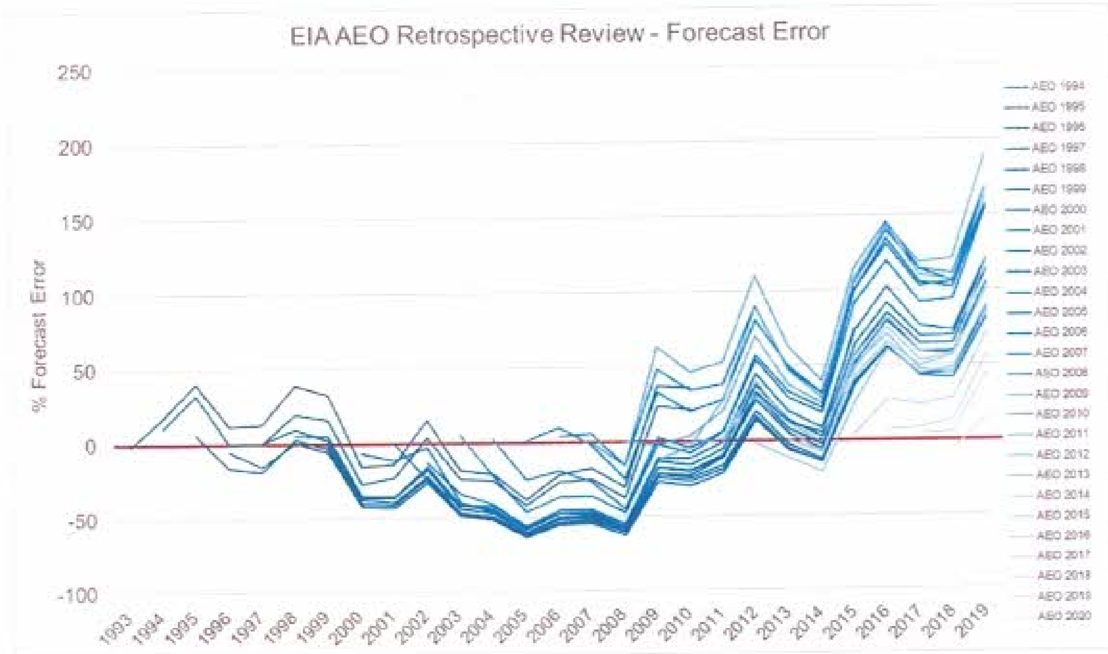

Figure 29 - EIA AEO Retrospective Review - Forecast Error

Despite Duke's previous protestations, similar forecast errors are also present in market prices. Figure 21 above showed the price of the January 2022 future dating back to 2013. In the summer of 2013, corresponding to the release of AEO 2012, the market projected that the price of natural gas in January 2022 would be $6.42 / MMBtu. AEO 2012 projected that it would be $6.022 / MMBtu.[144] In March 2020, the market thought the price for January 2022 natural gas would be $2.70, in October 2020 it thought it would be $3.20, and in late January 2021, it thinks it will be $3.12. Regardless of where the actual price of natural gas falls in January 2022, both the market and AEO long-term forecasts missed by similar amounts. This informs my recommendation to use the average of at least two fundamentals-based forecasts for the long-term portion of the natural gas price forecast.

Q120. ARE THESE TYPES OF FORECAST ERRORS PRESENT IN OTHER CRITICAL DATA POINTS IN THIS IRP?

[144] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2012&cases=ref2012&sourcekey=0.

A120. Yes. Duke's load forecast shows a similar forecast error, albeit with a slower correction than appears to be occurring in the AEO natural gas forecast. Figure 30 below shows the running ten-year forecast for DEC summer peak demand from 2012 through 2020.[145] DEC's summer peak demand actually shrunk at a compound annual growth rate ("CAGR") of -0.37% between 2010 and 2020 (solid red), while the weather-normalized values rose at a mild 0.06% CAGR (dashed red). Despite these consistent results, each year between 2010 and 2020, Duke's annual forecast for DEC summer peak demand continued to project load growth. Its forecast increased at rates of roughly 1.7% per year in the early 2010s before falling to roughly 1.0% per year in recent years, despite clear evidence of flat to declining load growth.

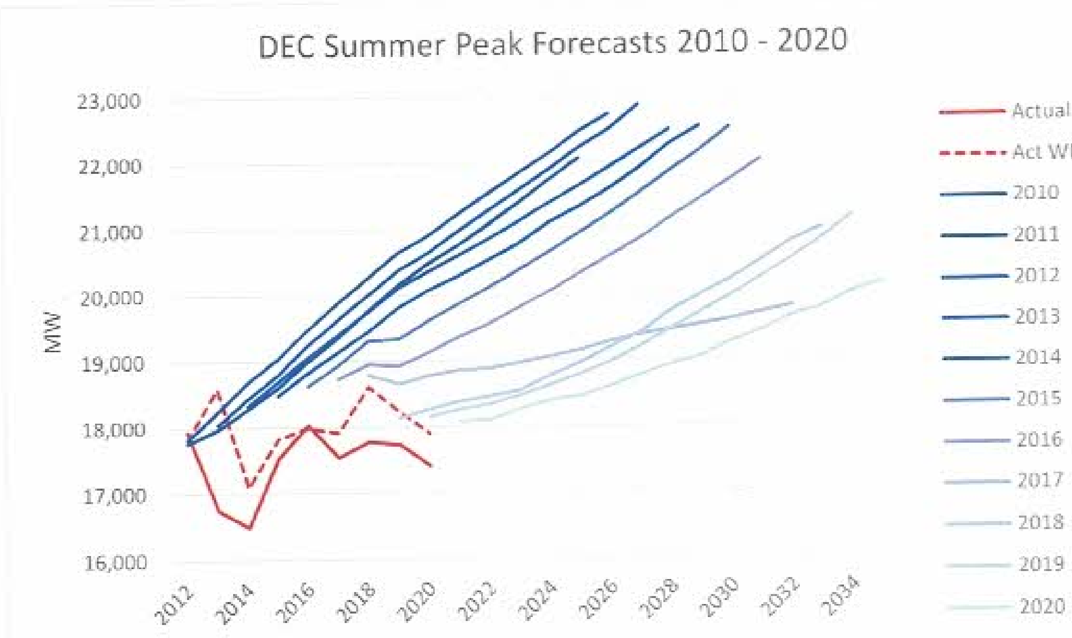

Figure 30 - Duke DEC Ten Year Summer Forecast

[145] Exhibit KL-18, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 3-12).

E. Duke's High and Low Natural Gas Price Sensitivity Methodology Exacerbates the Flaws of Using Market Prices in the Long-Term

Q121. DOES ACT 62 PROVIDE GUIDANCE ON FUEL FORECAST REQUIREMENTS?

A121. Yes, it does. Act 62 requires utilities to produce "sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks."[146] To fulfill this obligation, Duke produced a high and low natural gas price sensitivity. However, it did not produce any price sensitivities on coal, using a single base value for that fuel cost in all of its scenarios.[147]

Q122. HOW DID DUKE CONSTRUCT ITS HIGH AND LOW NATURAL GAS PRICE SENSITIVITY?

A122. Duke once again used a blended approach. It first produced a high- and low-price sensitivity for its market price forecast for years 1 through 10 before transitioning linearly to the high and low sensitivities of the AEO forecast from years 11 through 15 before moving fully to the AEO high and low sensitivities in year 16 forward.

The market price sensitivities were constructed through a statistical approach called a "geometric Brownian Motion model."[148] This model iterates through time, applying random increases or decreases in prices based on observed volatility of the natural gas futures market. Each run of the model will produce a slightly different futures curve, reflecting the randomness of Brownian motion.[149] Duke produced 1,000 futures price curve simulations and sorted them high to low, averaging the 95th through 105th result for the low price (10th percentile) estimate and 895th through 905th result for the high price (90th percentile) estimate. This process was repeated 10 times with Duke averaging each run's high and low price to produce the final high and low simulated futures curve.

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146 S.C. Code Ann. § 58-37-40(B)(1)(e)(iii).
147 DEC IRP Report at 157.
148 Exhibit KL-17.
149 Brownian motion describes small, random motion of particles in a medium. It is the mechanism through which diffusion occurs.

Q123. What is the underlying cause of the resulting 10th and 90th percentile fuel forecast schedules using this method?

A123. Randomness. This approach is roughly equivalent to using a Plinko board to produce fuel price sensitivities.[150] The underlying price volatility (i.e. daily price fluctuations driven by factors such as weather) is a measure of how quickly each iteration can deviate from that month's central value price. As the model iterates, most results will "revert to the mean" and remain relatively close to the central value of the baseline forecast. But in some runs, like in Plinko, the final value manages to migrate substantially to the high or low side of the distribution through random chance. If one were to graph the results of the 10,000 runs, one would expect to see a progressively wider normal distribution around each successive month's central value.[151]

Q124. How does this approach contrast with the fundamentals-based approach to high- and low-price sensitivities?

A124. While Duke's market price sensitivities rely on randomness to determine high and low prices, fundamentals-based models tweak parameters in their highly-integrated model to simulate shifts in supply or demand that will cause prices to rise or fall. EIA's AEO has two scenarios that specifically adjust production and supply of oil and natural gas: "In the High Oil and Gas Supply case, lower production costs and higher resource availability allow higher production at lower prices. In the Low Oil and Gas Supply case, EIA applied assumptions of lower resources and higher production costs."[152] In these scenarios, prices are not based on random price volatility in a futures market already struggling to deliver robust long-term projections,

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[150] Plinko was a popular game that debuted on the Price is Right in 1983. It featured a pegboard with many rows of offset pegs set in a hexagonal pattern. Contestants would drop discs in the top of the board where they would randomly bounce left and right while falling through the rows of pegs. The discs eventually finished in a slot at the bottom of the board which contained a specific cash prize.

[151] This assumes the volatility of price swings is symmetric. If the initial data set has a higher chance of prices increases than price decreases, then the distribution will be skewed towards higher prices.

[152] *Critical Drivers and Model Updates*, EIA AEO 2020. Available at https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Critical%20Drivers%20and%20Model%20Updates.pdf.

but rather rise and fall in a manner that simulates and incorporates the economic feedback loops that would come along with supply changes.

Q125. HOW DO DUKE'S HIGH AND LOW MARKET PRICE FORECASTS COMPARE TO THE HIGH AND LOW AEO PRICE?

A125. The baseline market price forecast limits the range of the high and low market price sensitivities in the early years. This produces a result where the high market price sensitivity is actually lower than the AEO Reference case between 2025 and 2034, and is much lower than the price projected in the AEO Low Supply (i.e. high price) case. Similarly, AEO's High Supply (i.e. low prices) case is well above the low market price sensitivity. Figure 31 below shows this relationship, with NYMEX representing Duke's market price forecast.

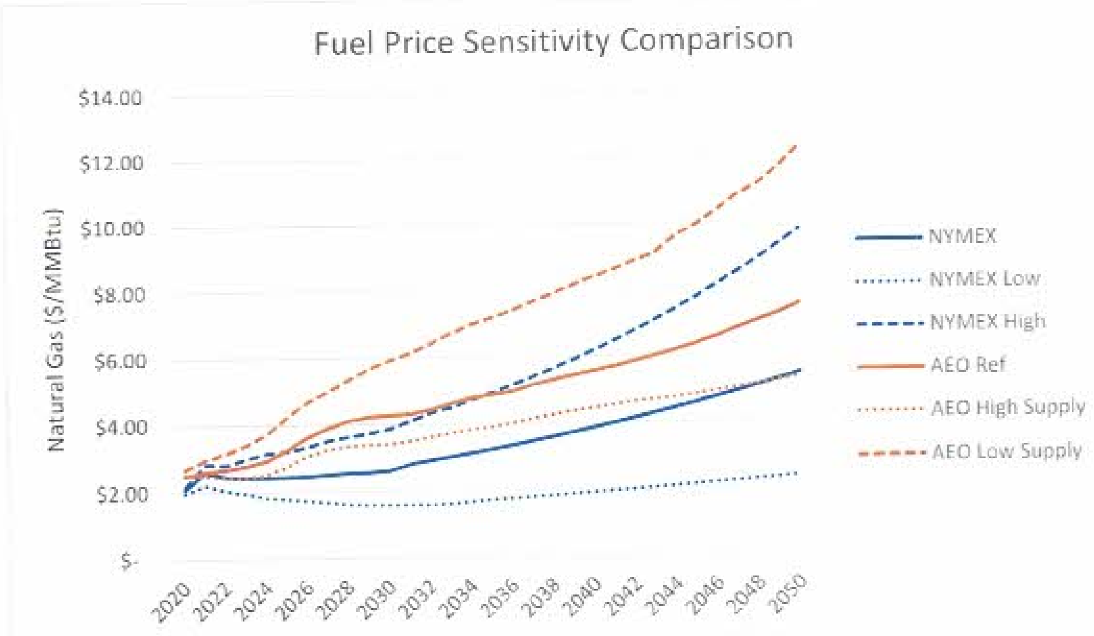

Figure 31 - Fuel Price Sensitivity Comparison

Q126. DOES MERGER OF A RANDOM-WALK FORECAST AND A FUNDAMENTALS-BASED ALTERNATIVE SCENARIO FORECAST SENSITIVITY TO PRODUCE A UNIFIED HIGH-PRICE AND LOW-PRICE NATURAL GAS SENSITIVITY MAKE SENSE?

A126. No. There is no correlation between the statistical analysis Duke applied to the market prices to simulate high- and low-price sensitivities and the scenario-based AEO cases used to build the high- and low-price sensitivities in the fundamentals-based forecast. Merging the two together carries forward the flaws of Duke's baseline forecast into the natural gas price sensitivities required by Act 62.

The arbitrary nature of the resulting forecast is evident in the low gas price scenario. Figure 32 below, a reproduction of the DEC IRP Report Figure A-2, shows the implausible result that Duke's approach produces. Duke expects the natural gas industry to reduce prices after inflation by 3.5% per year in the 2020s, then increase at an annual rate of more than 18% between 2030 and 2035, before slowing growth to an annual rate of 2.9% from 2036 and beyond. It is difficult to fathom a combination of policy scenarios that would produce this curve exactly because no combination of policy scenarios would produce this curve.

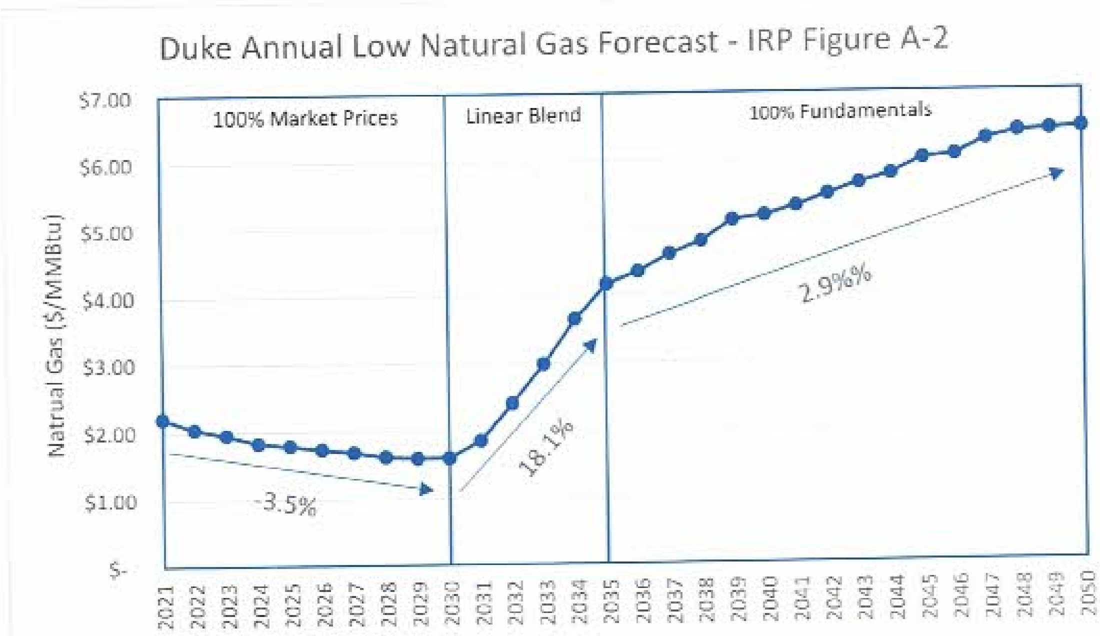

Figure 32 - Duke Annual Low Natural Gas Forecast - IRP Figure A-2

By contrast, the low-price scenario from AEO is internally consistent. Figure 33 below shows the annual results from this case overlaid with Duke's low-price sensitivity. Gone is the rapid directional switching, replaced by more modest moves as the feedback mechanisms in the fundamentals-based model incorporate higher supplies and lower prices.

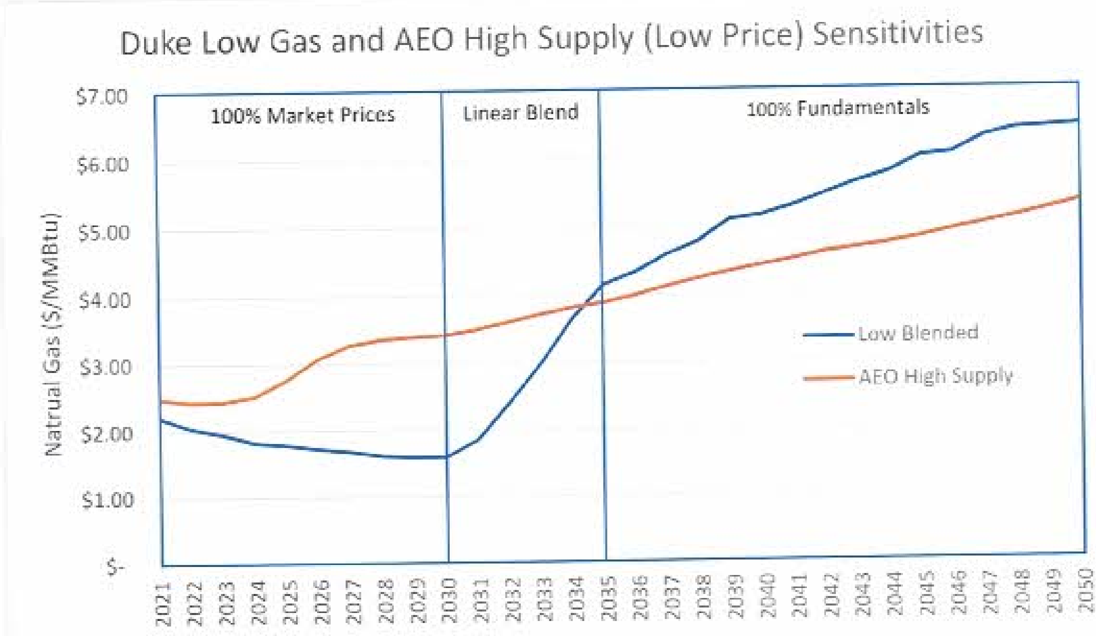

Figure 33 - Duke Low Gas and AEO High Supply (Low Price) Sensitivities

Q127. HOW DOES DUKE'S CHOICE TO USE THE 10TH AND 90TH PERCENTILE RESULTS IMPACT THE RESULTING SCHEDULE?

A127. The use of the 10th and 90th percentile results drove a larger discrepancy between the market prices and the fundamentals-based forecast. The high- and low-price sensitivities are important to demonstrate how Duke's fleet will respond to changes in the market, but using values from one-in-ten likelihood forecasts are more extreme and less likely than necessary for this purpose.

Even though under my recommendation market prices are only used for 36 months, the construction of the high- and low-price scenarios in that timeframe is still based on random chance based on the volatility of the market. I recommend that Duke instead use the 25th and 75th percentile results from this analysis. By selecting relatively more likely outcomes from the 25th and 75th percentile, the potential for the market prices to move too far from the central value is reduced.

Q128. DID DUKE CONSTRUCT SIMILAR FUEL COST SENSITIVITIES FOR COAL?

A128. No, it did not. Duke limited its fuel cost sensitivities to natural gas, stating: "By only changing natural gas prices, the impact on resource selection (CC vs CT vs Renewables) and dispatch (coal vs gas) can be evaluated."[153] Duke's failure to develop and analyze a high coal price scenario from either market conditions or regulatory changes, is problematic. Coal generation faces outsized regulatory risk and market pressures in the near future compared to the past. Changes in federal regulations may either require costly upgrades to maintain compliance or increase the running costs of coal units. For instance, EPA estimates that installing SCRs on units such as those at Marshall would cost roughly $100 million for a 300 MW unit and roughly $200 million for a 700 MW unit.[154] This could in turn impact the economic timeline for coal unit retirements, which could require additional replacement capacity to come online earlier.

Q129. WHAT DO YOU RECOMMEND WITH REGARD TO THE FUEL PRICE SENSITIVITIES?

A129. The issues shown above will disappear if Duke switches to the forecast methodology I described for the base scenario of relying on market prices for eighteen months before transitioning over eighteen months to the average of at least two fundamentals-based forecasts. The random nature of the Brownian model cannot move too far away from the central baseline market price forecast after only 36 months as there are simply fewer iterations to produce deviations. Maintaining the same blending method between 18 and 36 months will allow near-term market volatility to initially displace and then phase into the average of the early years prices from at least two fundamentals-based models.

I also recommend that Duke construct a high coal price scenario to reflect the increasing regulatory and market risk associated with the continued operation of its coal plants.

[153] DEC IRP Report at 157.
[154] EPA Platform v6. Available at https://www.epa.gov/sites/production/files/2018-05/documents/epa_platform_v6_documentation_-_chapter_5.pdf.

F. Duke's Reliance on Market Prices for Ten Years has Likely Skewed the IRP's Results

Q130. WHY IS THIS DISCUSSION ABOUT DUKE'S NATURAL GAS PRICE FORECAST IMPORTANT TO THE IRP?

A130. It is important because the natural gas price forecast and corresponding high- and low-price sensitivities are critical input assumptions to Duke's modeling. For a variety of reasons, Duke plans to close its coal facilities over the coming decades. The energy and capacity that these plants produce must be backfilled by some combination of resources. One of the primary goals of the IRP modeling is to determine which resource mix of demand-side management, renewable generation, fossil generation, and battery storage provides the most reasonable and appropriate blend. The natural gas fuel price input is particularly crucial in determining whether more renewables and batteries are selected by the model, or whether is it less costly to expand natural gas capacity (despite the stranded asset risk discussed previously).

Figure 34 and 35 below overlays Duke's annual central natural gas cost assumption with the additions from its modeling runs in the Base with Carbon Policy and Earliest Practicable Coal Retirement portfolios. Several thousand MW of new combined cycle plants are added in 2027 and 2028 in part based on the low natural gas prices that are prevalent through the early 2030s. If Duke's natural gas price forecast had reflected the recommended market price / fundamentals approach discussed above, prices in the mid-2020s and early 2030s would have been higher, increasing the PVRR of building and running natural gas plants.

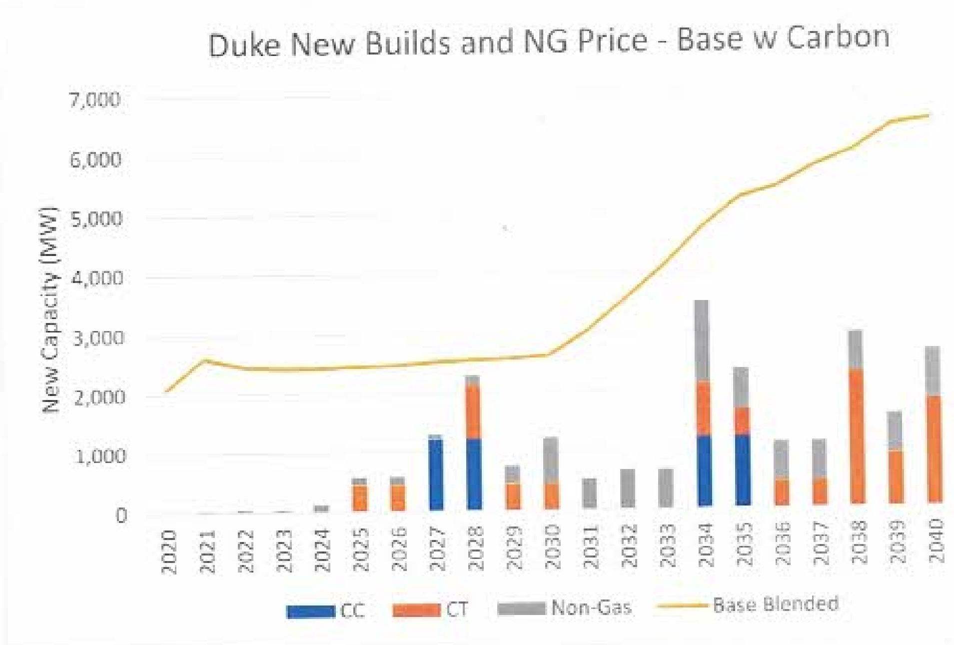

Figure 34 - Duke New Builds and NG Price - Base w Carbon

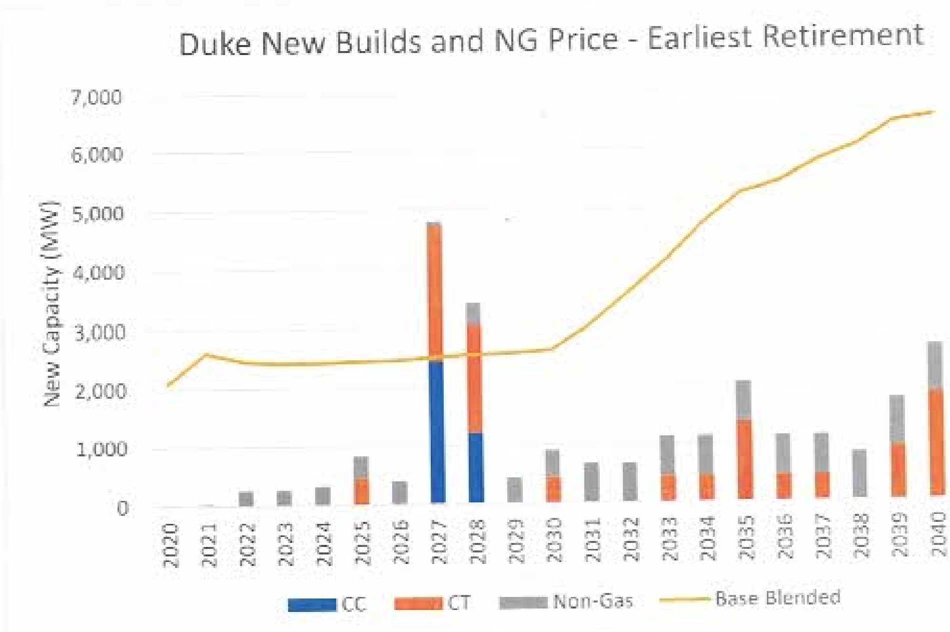

Figure 35 - Duke New Builds and NG Price - Earliest Retirement

Q131. Does the low natural gas price forecast affect other modeling outcomes?

A131. It could affect the model's decision whether to add new renewable generation even when there is no capacity need, although as discussed in Section III above, Duke has not enabled this option. With a higher natural gas price forecast, running existing or constructing new natural gas facilities would be relatively more expensive. This would provide an opportunity for solar, wind, and battery resources to economically displace new builds of natural gas or substitute new renewable builds for existing natural gas generation.

Q132. HOW DOES DUKE'S FORECAST COMPARE TO THE METHODOLOGY YOU RECOMMEND?

A132. Duke's central near-term forecast based on market prices is well below the fundamentals-based models. Figure 36 below shows the annualized prices for the Duke's base forecast ("Duke Blend"), a newly updated blend based on my recommended methodology ("Updated Blend", and the full range of market prices ("NYMEX"), IHS Makit's forecast ("IHS"), and the 2020 AEO Reference case ("AEO Ref").[155]

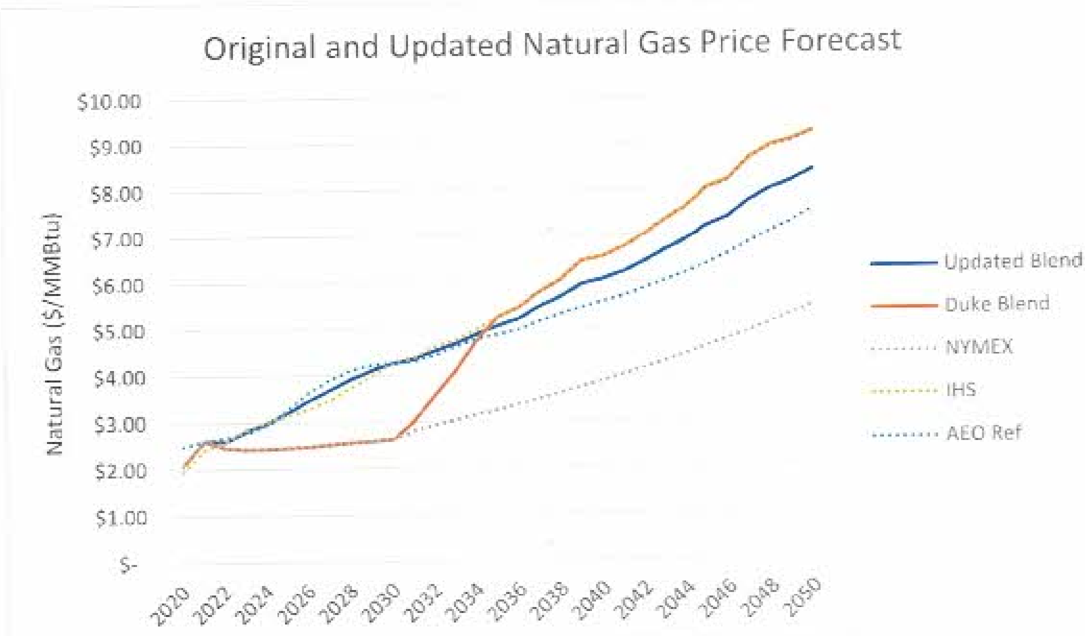

Figure 36 - Original and Updated Natural Gas Price Forecast

The two fundamentals-based models track each other closely through roughly 2035, when IHS rises above AEO. By taking the average of these two forecasts, prices are projected to be quite a bit higher in the 2020s and the early 2030s than in Duke's original base forecast.

[155] Exhibit KL-19, Duke Response to SCSBA RFP 2 (producing Duke response to DR ORS 2-3).

This change would present the model's optimization routines with a very different picture when natural gas is at [redacted]/ MMBtu than when it is at [redacted]/ MMBtu.

Q133. DO YOU HAVE ANY FINAL OBSERVATIONS ON THIS ISSUE?

A133. Yes. It's tough to make predictions, especially about the future.[156] Duke's preference for long-term market price forecasts is fundamentally flawed. Ten years is simply too long to rely on contracts priced on highly volatile financial derivatives. The contracts that underpin Duke's market price forecast are subject to sizable and frequent price shifts. The long-term prices that form the basis for the first ten years of Duke's natural gas price forecast are derived from illiquid markets and inappropriately reflect short-term volatility in long-term prices. Further, the prices of these contracts can fluctuate wildly in the span of a few weeks. It is wholly inappropriate to base ten years of future fuel prices on what is essentially a toss of the dice.

Duke's refutation of fundamentals-based forecasts made in other proceedings falls flat. It is true that market prices, which settle daily, move faster than fundamentals-based models, which are updated once or twice a year. Yet the frequency with which market prices move is not necessarily reflective of more accurate pricing. The rapid and sizable price swings of 2020 clearly demonstrates that market prices ten years out can be substantially impacted by short-term market volatility. It is a fallacy to believe that policies that could drive 10% to 15% price changes ten years in the future would shift back and forth week to week.

Duke should change its natural gas forecast methodology to leverage market prices where they are most liquid, while appropriately blunting the natural volatility in natural gas futures markets. By constructing a market price forecast based on a full month of futures contracts settlement prices, Duke can temper the abundant short-term market price volatility. Using this market price forecast over eighteen months before fully transitioning to a fundamentals-based forecast over the next eighteen months leverages the information from the liquid futures market while not allowing it to overstaying its welcome. This approach should

[156] RIP Yogi Berra.

also be applied to the high- and low-price sensitivities; Duke's current "random walk" approach to price variation has no place beyond three years.

The fundamentals-based forecast should be derived from the average of at least two reputable sources, including EIA's open-source AEO. This approach limits the reliance on one single forecast in much the same way that averaging a month of futures prices mitigates overweighting a single set of market prices. Marrying these two forecasts together should provide Duke with a much more robust natural gas forecast on which to base its IRP.

V. DUKE OVERLOOKS THE BENEFITS OF REGIONALIZATION

Q134. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A134. In this section, I discuss the role that regionalization could play in the planning and operation of Duke's system. I show how Duke's own modeling shows the benefit of enabling capacity sharing between DEC and DEP, and how increasing import capacity from neighboring regions could further reduce costs and increase reliability.

Q135. WHAT ARE YOUR PRIMARY FINDINGS?

A135. Duke has already performed modeling that shows the benefits associated with basic levels of regionalization, that is, firm capacity sharing between DEP and DEC and allowing for imports from neighboring systems. However, it has failed to pursue regulatory approvals that would let it operationalize some of these steps. Duke should proactively seek changes that would allow it to file joint IRPs between DEC and DEP and plan and operate its two companies in a manner that minimizes costs for all its customers.

Duke should also explore the potential benefits of broader regionalization through structures such as energy imbalance markets ("EIM") or regional transmission organizations ("RTO"). While Duke has supported the creation of the Southeast Energy Exchange Market ("SEEM"), due to its limited scope that organization would provide only a fraction of the potential benefits that a broader regionalization approach could bring.

A. *Increasing Regionalization can Reduce Costs and Increase Reliability*

Q136. PLEASE DESCRIBE THE BASIC TOPOLOGY OF DUKE'S POWER GRID AS MODELED IN ITS RESOURCE ADEQUACY STUDY.

A136. In Astrapé Consulting's DEP and DEC 2020 Resource Adequacy study ("RA Study"), it properly assumed that Duke's companies were interconnected to several neighboring systems. Figure 37 below is taken from the RA Study and shows the east and west region of DEP and DEC along with other systems such as TVA, PJM, and Southern Company.

Figure 1. Study Topology

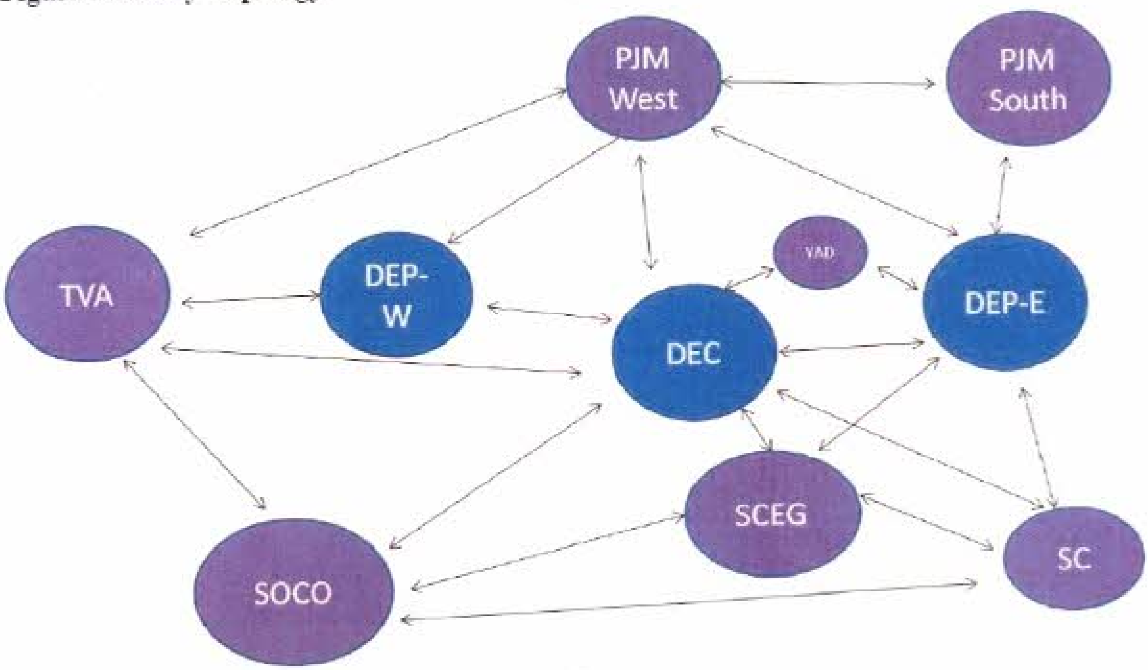

Figure 37 - Resource Adequacy Study Topology

Q137. HOW MUCH POWER CAN DUKE IMPORT FROM THESE REGIONS?

A137. The import limits vary based on the region. Table 6 below shows the import limits from each region in the summer and winter.[157] In addition to the figures below, DEC can export [redacted] MW to DEP-E, [redacted] MW to DEP-W, and transmit [redacted] MW from DEP-E to DEC to DEP-W.

[157] DEP IRP Attachment 3 Confidential Appendix_2020_Final, DEC IRP Attachment 3 Confidential Appendix_2020_Final.

For reference, DEP's and DEC's 2021 winter peak load forecast is 14,118 MW and 17,725 MW, respectively.[158]

From	Summer			Winter		
	DEC	DEP	Total	DEC	DEP	Total
[redacted]						

Table 6 - DEP and DEC Import Capacity

Together, DEP and DEC have the ability to import 7,108 MW from neighboring balancing areas in the winter, in addition to DEC's transfer ability to DEP. This represents a substantial fraction of Duke's winter peak demand level.

Q138. DO ALL OF THESE OTHER REGIONS EXPERIENCE PEAKS AT THE SAME TIME AS DEC AND DEP?

A138. No. Astrapé performed a load diversity analysis and found that neighboring utilities had spare capacity during the times when either the regional system or DEC and DEP individually were at their peaks. During the overall winter system peak, individual regions were roughly 2%-9% below their individual peaks. Further, when DEC was at its peak, DEP was 2.8% below its peak load and other regions were between 3%-11% below their peak loads.[159] When DEP was at its peak, DEC was 2.7% below its peak load and other regions were between 3%-9% below their peak loads.[160] This suggests that not only do these other regions have the physical ability to provide capacity to DEP and DEC during their winter peaks, but they have capacity to spare as well.

[158] 2020 IRP_ Model Inputs_NON-CONFIDENTIAL.
[159] DEC RA Study at 28.
[160] DEP RA Study at 27.

Q139. WHAT IMPORT CAPACITY LIMITATIONS DID ASTRAPÉ AND DUKE USE IN ITS RA STUDY?

A139. Astrapé and Duke ran several scenarios that modified the import capacity limits. The first case was an "island" case, where all resources must be in the physical footprint of DEC or DEP. Unsurprisingly, this required a very high reserve margin to meet the standard of 0.1 LOLE per year, with a 22.5% requirement in DEC and a 25.5% requirement in DEP.[161,162] This island configuration is not reflective of how Duke's systems are physically configured, and thus Astrapé ran the Base case allowing imports from neighboring regions. This reduced the reserve requirement in DEC to 16.0% and in DEP to 19.25%[163]

Astrapé also modeled a "combined case" where both utilities were treated as a single entity. This model produced a combined reserve margin requirement of 16.75%.[164] One last sensitivity was performed that limited the imports into the combined utility to 1,500 MW, well below the actual import capacity. This adjustment increased the reserve margin to 18.0%, showing the cost benefits associated with utilizing spare regional capacity.[165]

Q140. DID THE COMBINED CASE RESULT IN DELAYS IN NEW CAPACITY?

A140. Yes. By modeling a Joint Planning case with a combined DEC and DEP, Duke was able to delay the addition of several CTs. It also resulted in a lower overall reserve margin. As Duke indicated, "[t]he ability to share resources and achieve incrementally lower reserve margins from year to year in the Joint Planning Case illustrates the efficiency and economic potential for DEC and DEP when planning for capacity jointly."[166]

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[161] Loss of Load Expectation. The 0.1 LOLE is roughly equivalent to experiencing one load shed event in ten years.
[162] DEP IRP Report at 67, DEC IRP Report at 65.
[163] DEP IRP Report at 67, DEC IRP Report at 65.
[164] DEC IRP Report at 66.
[165] DEP RA Report at 61.
[166] DEC IRP Report at 200.

Q141. Despite the obvious benefits associated with planning and managing capacity jointly, does the Company currently plan and manage capacity jointly between DEC and DEP?

A141. No, it does not. While the Company has a Joint Dispatch Agreement ("JDA") in place, outside of emergency situations, it is limited to economic non-firm energy transfers.[167] It also does not perform a unified IRP for the combined companies, nor plan for capacity jointly between the two companies.

Q142. Why does Duke not integrate its operations and planning efforts more thoroughly?

A142. Duke's response to this question was that they currently do not have authorization to either submit a unified IRP[168] or share long-term capacity.[169] It further noted that such authorization would be required from the Federal Energy Regulatory Commission ("FERC"), the North Carolina Utilities Commission ("NCUC"), and the Public Service Commission of South Carolina ("PSCSC").[170]

Q143. Is anything stopping Duke from pursuing these authorizations?

A143. There does not appear to be anything preventing the Company from pursuing these changes. Duke stated "[i]f and when a decision were to be made to file a unified IRP that covers both territories or to merge the balancing areas across [North Carolina] and [South Carolina], the Company would seek appropriate regulatory approvals."[171] The response is ambiguous as to who would be making the decision, but Duke did not identify any legal roadblocks to seeking a change in status.

Q144. What do you recommend on this matter?

[167] Exhibit KL-20, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-12).
[168] Exhibit KL-21, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-13).
[169] Exhibit KL-20.
[170] Exhibit KL-20.
[171] Exhibit KL-22, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 4-2).

A144. I recommend the Commission direct Duke to study the impact of joint planning of and long-term capacity sharing across its two systems and prepare a feasibility study on merging these functions across the two utilities. Based on high-level analyses presented in this docket, it appears that cost savings are available through this effort. Arrangements could be made between DEC and DEP that would realize and pass these cost savings onto the customers of each utility.

B. *Duke Should Analyze the Benefits of Broader Regionalization*

Q145. ASIDE FROM POTENTIALLY DEEPENING ITS JDA TO INCLUDE PLANNING AND FIRM CAPACITY TRANSFERS, ARE THERE OTHER REGIONALIZATION BENEFITS THAT DUKE COULD CONSIDER TO FURTHER REDUCE COSTS TO ITS CUSTOMERS?

A145. Yes. Duke has already expressed interest in joining SEEM, a very small step towards regionalization that would allow companies to voluntarily execute bilateral contracts for as-available energy in fifteen-minute blocks. This marketplace could potentially save participating utilities in the Southeast $40-50 million annually in the near term, potentially increasing to $100-$150 million in the long term.[172]

Q146. HOW DO THESE SAVINGS COMPARE TO THE POTENTIAL VOLUME OF ELECTRICITY SALES FROM THE FOUNDING MEMBERS?

A146. It is miniscule. Founding members of SEEM are expected to include some of the largest utility companies in the southeast, including Associated Electric Cooperative, Dalton Utilities, Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, ElectriCities of North Carolina, Georgia System Operations Corporation, Georgia Transmission Corporation, LG&E and KU Energy, MEAG Power, NCEMC, Oglethorpe Power Corp., PowerSouth, Santee Cooper, Southern Company, and TVA.[173] Considering DEC and DEP spend billions of dollars annually apiece on electricity, $40 million per year from this

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[172] https://news.duke-energy.com/releases/southeast-electric-providers-to-create-advanced-bilateral-market-platform.
[173] *Id.*

consortium of large utilities is a drop in the bucket of what benefits broader and deeper regionalization could bring.

Duke appears to acknowledge that SEEM will not be integral to its operations or planning going forward. When asked about how SEEM will change their IRP assumptions, Duke responded: "Since SEEM is a sub-hourly non-firm energy only market, SEEM is not expected to be foundational to future IRPs."[174]

Q147. ARE THERE OTHER STRUCTURES THAT COULD INCREASE SAVINGS FURTHER COMPARED TO SEEM?

A147. Yes. The Western EIM has more robust features, including both a 15-minute and 5-minute market and an independent market monitor.[175] Since its formation in in November 2014, the Western EIM has saved its participants $1.2 billion, including $325 million in 2020 alone.[176]

But even the Western EIM does not currently feature a day-ahead market, where the vast majority of energy transactions are handled, nor implement transparent nodal pricing (e.g. LMPs). These are features associated with regional transmission organizations ("RTOs") and represent an even deeper commitment to regionalization. RTOs such as PJM and MISO function as transmission system operators and coordinate wholesale markets in energy, capacity, and ancillary services. By extending planning and dispatch over a broad geographic area, RTOs can maximize the benefits of geographic diversity in load shape, weather, and generation assets. In contrast to the limited SEEM proposal, a broader southeast RTO could save customers up to $384 billion through 2040.[177]

Q148. HAVE THERE BEEN RECENT ACTIVITIES ON REGIONALIZATION IN SOUTH CAROLINA?

A148. Yes. Governor McMaster signed H. 4940 into law last fall.[178] This law creates a legislative committee and advisory board that has until fall 2021 to study changes to the electricity sector

[174] Exhibit KL-6.
[175] https://www.westerneim.com/Pages/About/HowItWorks.aspx.
[176] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.
[177] https://caper-usa.com/news/south-carolina-law-pushes-for-power-market-reform-floats-creation-of-rto/.
[178] S.C. Act No. 187 (2020). Available at https://www.scstatehouse.gov/sess123_2019-2020/bills/4940.htm.

in South Carolina, of which the South Carolina President of Duke Energy is a member. The study must investigate potential reforms such as creating a new RTO, joining an existing RTO, establishing an EIM, restructuring power generation, and offering full customer retail electric choice.[179]

Duke should bring its expertise to the committee and help detail the potential benefits and challenges associated with regionalization. It will be critical that Duke provide information objectively, recognizing that some benefits of that come with regionalization could put downward pressure on Company revenues and profits. However, as shown by the buildouts needed to transform the electricity sector in South Carolina, there will be no shortage of investment opportunities in new, clean generation and transmission assets.

VI. CONCLUSION

Q149. PLEASE PROVIDE YOUR OVERALL CONCLUSIONS OF DUKE'S IRP.

A149. Duke's IRP fails to comply with Act 62 and the Commission should require modifications to its filing. The Company fails both to identify a single Preferred Resource Plan and to provide the Commission with sufficient information from which it could determine what is the most reasonable and prudent means to meet Duke's identified energy and capacity needs. Duke risk analysis is very limited and does not adequately address regulatory risks associated with its natural gas buildout or continued operation of coal plants in its Base portfolios. These risks are readily identified using a straight-forward analysis, demonstrating the downside economic risk of carbon prices, regulatory changes, or high fossil fuel on any scenario that does not rapidly move away from fossil fuels.

Duke's modeling methodology and input assumptions must be revisited. The recent extension of the federal ITC must be incorporated into solar and solar plus storage capital costs. Similar to DESC, Duke erroneously did not allow the model to add new capacity or PPAs

[179] *Id.* § 2(B).

unless there was a capacity need, eliminating the potential to incorporate less-expensive energy-only resources earlier in the planning horizon. Duke also overstated its PV fixed O&M cost assumptions and did not accurately reflect the existing or likely future mix of fixed-tilt vs. single-axis tracking systems. The Company failed to allow two-hour batteries despite their ability to provide meaningful capacity credit at lower costs. Finally, Duke's development timeline for SMR and pumped hydro do not comport with the Company's own data.

Duke natural gas forecast relies far too long on fickle market prices, a fatal flaw of that permeates its entire IRP planning horizon. This approach codifies long-term prices that are disproportionately impacted by short-term volatility and diverge substantially from prices projected by fundamentals-based forecasts, as is demonstrated vividly in the Company's high- and low-price sensitivities. The Company should instead rely on market prices for a much shorter period, using them for eighteen months before switching fully over to a fundamentals-based forecast by 36 months. It should also adjust its high- and low-price scenarios to reflect the 25th and 75th percentile results and develop a high-cost coal case to account for the myriad regulatory risks faced by coal generation.

Finally, the Company should embrace the cost savings that come with broader regionalization and begin to explore the implications of unifying its planning and operations of DEC and DEP. Duke should not be satisfied with the limited benefit of joining SEEM but should explore more robust regionalization strategies such as forming or joining an RTO.

If Duke were to make these updates to its modeling, it is likely that cost-optimal portfolios will feature earlier coal retirements, lower natural gas builds, and higher and earlier solar, solar plus storage, and standalone storage deployment. These updated portfolios will enable Duke's customer to reap the benefit of the federal ITC extension while jumpstarting Duke's progress towards its own 2050 net zero goals.

Q150. DOES THIS CONCLUDE YOUR TESTIMONY?

A150. Yes, it does.